October 15, 2008

Philip Giudice, Commissioner
Massachusetts Department of Energy Resources
100 Cambridge Street, Suite 1020
Boston, MA 02114

Re: Comments – Class I RPS

Dear Commissioner Giudice:

SunEdison LLC (SunEdison), North America's largest solar energy service provider, appreciates the opportunity to comment on the development of Massachusetts' emerging customer-sited renewable set-aside program. The Green Communities Act (GCA) provides an historic opportunity for Massachusetts to significantly expand the contribution of clean, stable-priced, and renewable energy sources such as solar photovoltaics (PV) to the state's resource mix.

Massachusetts has all the fundamentals for a robust distributed solar photovoltaic market – high utility rates, an excellent solar resource and ample roof space, a highly skilled labor force, and a strong environmental ethic. Solar energy represents an attractive modern alternative to Massachusetts' legacy power plants and aging grid, particularly in densely populated metropolitan areas. Solar energy is an effective means to reduce air pollution and fight global warming, reduce stress on the electric grid, increase energy independence, promote new economic investment, create good new jobs and protect all consumers in the Bay State from the adverse impacts of expensive peak power purchases.

As described below, in order to tap this resource, it is essential that Massachusetts policy makers establish a specific solar PV technology share within the customer-sited renewable set aside program. The best means of driving solar PV development at the least cost to ratepayers is through a market-based program, with specific, significant and growing annual deployment targets and an accompanying technology-specific solar alternative compliance payment (SACP) schedule.

I. EXPERIENCE IN MASSACHUSETTS AND ACROSS THE COUNTRY DEMONSTRATES THAT A SOLAR SET-ASIDE IS REQUIRED TO ACHIEVE GREATER RENEWABLE RESOURCE DIVERSITY

Massachusetts and some 25 other states across the country have established some form of a renewable portfolio requirement; yet not all these states have enjoyed equal success in creating a vibrant distributed solar PV marketplace. Rather, significant PV development is occurring only in those states that have made a separate and distinct commitment to solar PV.

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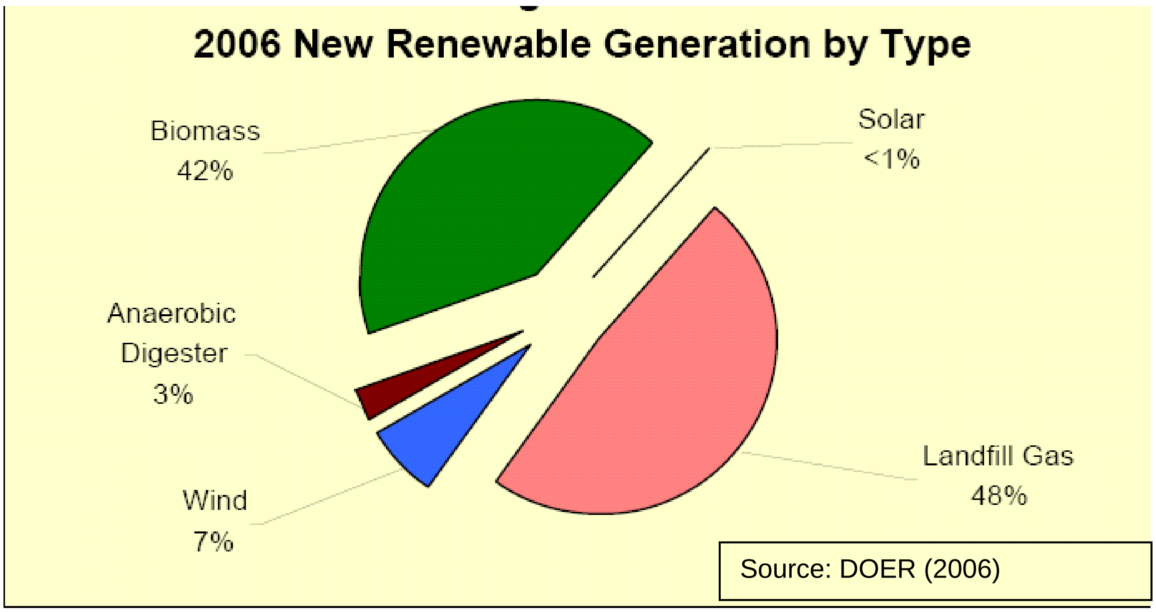
The reasons for this are manifold. Absent a specific solar mandate, utilities and other load serving entities subject to the RPS requirement will gravitate to the lowest cost option, which for most regions is wind, biomass, and hydropower (where eligible). Additionally, it is difficult for small-scale distributed renewables to compete effectively with utility-scale renewable resources in utility renewable solicitations and other procurement processes given the relatively higher administrative and other transaction costs per megawatt of installed capacity.

As reflected in the most recently published annual report for the RPS, only a very small fraction of the 2006 Massachusetts RPS obligation was satisfied from solar PV.[1]



Given the relatively low REC price set by regional biomass, landfill gas and wind facilities, Massachusetts-based PV has been dedicated to the voluntary market where it can command a much higher premium.

The lion's share of PV development is occurring in those states with a solar share requirement. Outside of California (which relies primarily on performance-based incentives), over 80% of all new U.S. PV capacity installed in the past decade is located in the states with a solar share requirement. It is no surprise that a growing number of states are recognizing the importance of differential treatment for solar PV within their respective RPS programs. Just within the past two

[1] Of a total RPS obligation of 1.25 million MWh's, only 216 MWh's was derived from RPS eligible solar PV. DOER, Massachusetts RPS Compliance Report for 2006, February 15, 2008.

years, six new state solar requirements have been established, representing nearly 2500 MW in additional PV deployment commitments.[2]

The GCA explicitly grants to DOER the authority to establish technology-specific bands within the customer-sited renewable set aside. We strongly encourage the DOER to exercise this authority by creating a distributed solar PV set aside with sustained growth targets through 2017.

II. Overall and Annual Solar PV Deployment Goals Should Facilitate the Sustained and Orderly Development of a Robust Market

A solar specific carve-out within the customer-sited renewable tier creates for the first time the real possibility for a sustained, sizable and stable solar PV market in Massachusetts. Setting an aggressive but realistic deployment goal will ensure that Massachusetts does its part to drive scale in solar module development with resultant cost reductions. More importantly, setting aggressive state-based targets is the only way to achieve true market transformation - the establishment of a skilled and efficient work force to install and maintain systems, the development of dealer networks and sales teams, training of local code and permitting officials and other infrastructure development that is of an inherently local nature. It is only through the creation and satisfaction of local demand that state and regional markets will gain experience and grow in maturity. The following discussion focuses on considerations for setting the terminal and interim yearly targets.

A. Establishing an Aggressive but Realistic Solar Program Stretch Goal

The Patrick Administration has embraced a 250MW solar PV goal by 2017 under the auspices of the Commonwealth Solar initiative. While this is a noteworthy milestone, we strongly encourage the DOER to revisit the 250MW target in light of the new authority vested in it by the GCA. Rather than treat the 250 MW goal as fixed and sacrosanct, the DOER should conduct or commission a rigorous analysis of the costs and benefits of achieving higher solar PV deployment targets. As noted below, the ability to shift from a program support mechanism that provides up-front incentives to one that is more dynamic and production based would allow the DOER to maximize the use of available public funds to achieve more ambitious targets.

Achieving 250 MW of installed capacity by 2017 will serve approximately .4% of Massachusetts retail load by the terminal year.[3] By contrast, several leading states have set solar targets of 1.5% of retail load or higher. These include California (1.5% or 3000MW): New Jersey (2.1% or 1700 MW): Arizona (2% or 1600 MW): Maryland (2% or 1500MW); and New Mexico (3.1% or 420MW). In absolute terms, two other states have recently set targets well in excess of the

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[2] For an excellent summary of these recent developments and on the importance of PV set-asides within an RPS framework, see Wiser, R., *Renewable Portfolio Standards: An Opportunity for Expanding State Solar Markets, July 11, 2008 (presentation to State PV Network)*, included with these comments as Attachment I.

[3] Assumes 1.55% annual load growth (Source: ICF Consulting, Assumption Document – Regional Greenhouse Gas Initiative Analysis, March 22, 2006) applied to 2006 base year load of 50.14 GWh's (Source: Mass. DOER, Annual RPS Compliance Report for 2006, February 15, 2008).

Commonwealth Solar benchmark. These are Ohio (820MW); and Pennsylvania (690MW) – two states not generally associated with renewable energy development in the past.

The electricity markets in the aforementioned states differ from Massachusetts in important respects -- solar insolation, retail electric rates, retail load – that will influence the attractiveness of solar PV as a resource option. The point is not that Massachusetts should simply adopt another states' target, but rather that Massachusetts should carefully assess the feasibility of more aggressive targets to accelerate the transition to grid parity.

Unfortunately, the Navigant study does not examine the economic potential for PV, and concomitant costs and benefits of alternative deployment targets. Rather, the study takes the 250MW solar target as a given and limits its analysis to fixing incentive levels needed to hit these targets.[4] Thus, it does not explore the costs and benefits of converting alternative amounts of the nearly 13GW of technically available solar resource identified.

As part of the formal rulemaking process, we urge the DOER to examine the costs and benefits of a solar PV deployment program ramping to 2% of retail load by 2017. On the benefit side of the ledger, the DOER should examine the multiple potential value streams of solar PV including the following direct system costs:

- Fuel price hedge protection;
- Peak avoidance;
- Transmission and distribution system loss avoidance;
- Deferral of distribution system upgrade and expansion;
- Avoided environmental compliance; and
- Reduction in ancillary service costs.

Additionally, in arriving at an appropriate PV deployment target, the DOER should endeavor to quantify the following societal benefits:

- Economic development and job creation;
- Avoided risk of blackouts and impairment of service quality; and
- Avoided environmental and public health impacts.[5]

B. The Solar Development Trajectory: Growing Interim Targets

In conjunction with the overall program goal, attention must be paid to the setting of specific annual targets. Again, the underlying principle is one of sustained and orderly development. Based on our experience, the better solar set aside programs follow these shared design characteristics:

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[4] Navigant Consulting, *Massachusetts Renewable Energy Potential – Final Report*, (August 2008) at Slide 7, 52-57.
[5] For a taxonomy of PV benefit streams and value ranges see Navigant Consulting, *Photovoltaics Value Analysis (February 2008), available at* < http://www1.eere.energy.gov/solar/solar_america/rsi.html >.

- "Backloaded" requirements. The first year or two of requirements should be comparatively modest, requiring perhaps 50% more solar than is currently installed in the state, so as not to overwhelm modest in-state installation capacity. Such capacity can and will develop rapidly in the face of adequate incentives, as seen in New Jersey, where several hundred new, qualified solar electric installers and thousands of installations have developed in just 5 years.

- Significant market size / exponential growth. The solar electricity industry – both globally and in leading states like New Jersey and California – is growing at an annual rate of 30–50%. Any requirement must grow at a rate of at least 20% annually to attract significant interest and maximize public benefits. Such targets can be met with relative ease by solar installers, who can bring projects to fruition in much shorter design/build cycles than conventional power developers.

- Long horizons. To attract and retain significant clean energy development is a demonstration it is equally important that the standard (and the market it creates) be transparent and reliable for a reasonable period into the future. This means that requirements must be stated for a minimum eight to ten-year period, and that even after year-over-year increases cease, the requirements remain in place such that long-term contracts may still be signed in out years.

III. THE DEPARTMENT SHOULD TRANSITION TO A MARKET-BASED SOLAR PROGRAM AS THE MARKET STRUCTURE MOST LIKELY TO FOSTER A ROBUST AND COMPETITIVE SOLAR INDUSTRY AT THE LEAST COST TO CONSUMERS.

Many states have recently elected to enact standards encouraging the increased development of solar through the use of a market-based portfolio mechanism. These portfolio mechanisms have a number of advantages as compared with other incentive mechanisms (such as tax or rebate-based approaches). In particular, they maximize competitive pressure to drive down clean energy prices and by design maximize eligible generation at lowest costs. We enumerate below a number of the all-important criteria that should influence DOER's model choice and why we believe a market-based portfolio mechanism is the best means of simultaneously satisfying these goals.

A. Criteria for Choosing an Appropriate PV Set Aside Program Structure

The overall goal of an effective state-based solar PV incentive program is to create a robust and self-sustaining market characterized by PV costs that are competitive with grid supply, a well-established supply chain and motivated consumers. Based on our experience as a market participant in virtually every solar RPS program across the country, certain principles underlie the most successful solar programs:

- Tie incentives to long-term deployment goals and solar market transformation objectives. Incentives should be offered in the context of building sustained, sizable and stable markets. The better functioning state incentive programs are connected to growing annual deployment targets over a period of a decade or more.

- Program readily adaptable to changing market conditions. One of the inherent difficulties in developing an effective solar program is the ability to calibrate consumer demand through incentive offerings. Better designed programs are capable of striking a balance such that the market is neither over-stimulated (leading to rapid depletion of incentive funds and the shutdown of the market) or under-incentivized (resulting in anemic growth). Moreover, programs that enable market participants to respond in real-time to the fluctuations in underlying market conditions should be favored.

- Minimize direct and indirect program costs. Program design should support achievement of Massachusetts' solar deployment goals at the lowest cost to ratepayers. This goal is fostered by market support mechanisms that are responsive to changing market conditions, impose discipline on market participants, and meet only the incremental financial needs of consumers to support project development. Additionally, this goal is furthered by a program design that minimizes administrative and transaction costs, and that eschews cumbersome oversight While the state or its ratepayers have every right to get the most bang for their incentive buck, models that require elaborate program administration may negate the value of the incentive from the perspective of the developer, the host site and customers at large, and may ultimately be self-defeating.

- Promote investor confidence. Program design elements that enhance the certainty of future revenue streams and market stability can enhance investor confidence. This will redound to the benefit of ratepayers through reductions in compliance costs - attracting capital to the marketplace, facilitating longer-term contracting, and reducing financing costs. We have found that those entities that have continually changed regulations create so much uncertainty in the market that buyers and sellers simply stop acting. The sales cycle for solar is long, and the engineering, procurement, construction schedule is long as well. Minor alterations in programs lead to cascading negative effects.

- Reward high-performing systems with appropriately designed incentives. Performance-based incentives, paid on actual energy production, inherently incentivize optimal system design and encourage active, ongoing maintenance efforts. The long term goals are to generate as many MWh from solar as possible, to encourage higher MWh production per MW, and to promote systems that maximize the time-value of generation and incentives should be devised accordingly.

- Enable incentives to be phased out over time. Incentives are needed today to jump-start a local solar industry, but the long term goal is to make the solar industry cost effective with grid power such that incentives are no longer necessary. The cost of solar panels is only part of the picture. As more solar is installed, we will see economies of scale, and competition which should lead to lower pricing. As those prices drop, incentives can drop and developers can still maintain the payback targets described above.

- Support a diversity of market segments. Access to the market should be afforded all customer classes and market segments including residential, commercial, industrial, public entities and non-profits.

B. A Solar Renewable Energy Credit (SREC) Trading Program is the Best Means of Maximizing These Objectives.

We strongly encourage the PSC to consider adopting a solar set-aside within the RPS, with modestly increasing deployment targets through 2017 and beyond. These targets would be satisfied through a more market-oriented trading platform, wherein recurring production revenues realized by project owners through the generation and sale of Solar Renewable Energy Credits (SRECs) to RPS-responsible entities will leverage private investment in solar facilities. An SREC trading program will enable Massachusetts to achieve its RPS goals at the lowest possible cost by attracting private capital, and by encouraging industry innovation and efficiency on the part of market participants.

In operation, the SREC Trading program would largely mimic the broader RPS program as it has been implemented in Massachusetts; namely:

- A multi-year solar deployment schedule would be established within the overall RPS with steadily increasing yearly growth targets;
- Generation from qualified behind-the-meter solar PV would create SREC's equivalent to one SREC for every MWh produced;
- Utilities and load serving entities would be responsible for purchasing their proportionate share of SRECs from solar system owners based on retail load served;
- Load serving entities would be encouraged to enter into long-term contracts for SREC's, or other means of "securitizing" future SREC revenue streams would be adopted;
- Load serving entities would be assessed a Solar Alternative Compliance Payment (SACP) for failure to procure a sufficient number of SRECs.

We agree with the need to provide access to the market for all segments. Within a market-based framework, MTC should continue its current role of providing incremental rebates to inherently high-cost or hard to reach market segments, including residential, small commercial, non-profits, public entities, etc. This is the best way to level the playing field and allow fair access to the SREC marketplace.

It must be underscored that as with any program structure the devil is in the details; it's easy to create a standard that fails to create a functioning market simply through the omission of one critical element. For example a flat RPS alone will develop almost no solar, as the retail cost structure of solar energy is much different than the wholesale structure used by, for instance, large wind farms. Sections IV-VII below highlight some of the more outcome determinative features of a market-based solar program.

IV. The SACP Must Be Set at a Level that Will Spur Consumer Investment in Solar PV.

Fundamentally, the SACP must be set at a level that will drive solar investment. This requires the Department to make certain judgments about the consumer's approach to solar energy as an investment. In essence, the Department must determine what will be an acceptable payback period for various customer segments and how the consumer will recover this capital investment through SREC payments and other incentive streams over the life of the system. Thus, the SACP value is sensitive to a number of critical program design elements. These include: 1) target IRR's for solar market segments; 2) the length of time over which a solar project can generate SRECs; 3) the availability of rebates and other incentives; and 4) solar PV cost degression. These issues are discussed in more detail immediately below.

SACP values recently established by other states range from approximately $450/MWh[6] to $711/MWh[7] and demonstrate the sensitivity of SACP values to alternative program parameters. Although we recognize the DOER is seeking recommendations herein on an appropriate SACP level, this level should be the *result* of other program design elements rather than the *starting point.*

A. Targeted Internal Rate of Return

An analysis of SACP levels must begin by determining the requisite payback or internal rate of return that will encourage the consumer to deploy behind-the-meter solar as an alternative to grid supply. Research confirms that different customer segments have differing investment criteria. Beyond early adopters (who may be motivated to install solar for a variety of non-economic reasons), simple paybacks on the order of 5 to 7 years are required to motivate commercial investment, while residential consumers expect at 10-12 year payback.[8] Meeting these investment criteria is crucial to economic viability and project feasibility.

[6] First year SACP for Maryland and (proposed) Ohio solar set aside programs. Pennsylvania does not publish an SACP in advance but rather sets their SACP at "200% of the average market value of SRECs transacted during that period". We do not recommend the Pennsylvania approach as it fails to send a clear forward price signal to the market.

[7] First year SACP value for New Jersey. New Jersey Board of Public Utilities Order No. EO06100744, Decision and Order Regarding Solar Electric Generation, dated Sept. 12, 2007 at 42.

[8] Summit Blue Consulting, *An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives* (hereinafter "New Jersey Solar Program Cost Study), available for download at http://www.njcleanenergy.com/files/file/2NJ-BPU%20SACP%20RPI%20Analysis%20Report-revised-0806.pdf August 2007 at 18-20.

B. Qualification Life

The period of time over which a customer-sited solar system is eligible to generate SREC's will strongly influence the economics of the individual project. The longer the qualifying life, the greater the ability for the system owner to recoup his/her initial investment at a lower SREC value. Conversely, the more compressed the qualification life, the higher the SREC value must be to meet the payback targets identified in the preceding section.

Qualification life will also have a bearing on the timing and total cost of the customer-sited program. A short qualification life will necessitate front-loading of recovery and drive up program costs in the short-term, while a longer qualification life will attenuate these costs.

We urge the Department to establish a minimum 15 to 20 year qualification life. Although considerably shorter than the typical life of a PV system, this term overlaps much of the useful life of the system during which it is providing the desired economic and environmental benefits. Moreover, this tenure is consistent with renewable procurement policies adopted in Massachusetts[9] and a number of other jurisdictions[10] moving to market-oriented solar incentive programs.

C. Factoring in Other Incentives

A key issue for the Department and others policymakers is whether rebates will continue to play a role in underwriting the economics of solar projects even after a market-based SREC trading system is instituted. As noted elsewhere, we recommend that up-front rebates be largely supplanted by a more flexible market-based incentive structure that rewards performance and is much better suited to respond to the dynamics of the solar market. However, rebates may have a continued role in the relatively higher cost small residential and commercial segments where SREC revenues alone will not support economic viability. To the extent incentives continue to be made available, this should be properly factored into a determination of the appropriate SACP level.

Similarly, the recent extension and expansion by Congress of the solar investment tax credit will enable Massachusetts to leverage federal funds to achieve its solar set aside. These incentives should likewise be factored in when calculating an appropriate SACP level.

It should be noted that one of the virtues of an SREC-based system is that the market should automatically recalibrate for future changes in incentive level and availability of other incentives.

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[9] See Chapter 169 of the Acts of 2008 (Green Communities Act), Section 83 (encouraging long-term contracting of 10-15 years for renewable energy and/or RECs by distribution companies).

[10] See, e.g., 4 Code of Colorado Regulations 723-3 (20 years); New Jersey Board of Public Utilities Order No. EO06100744, Decision and Order Regarding Solar Electric Generation, dated Sept. 12, 2007 at 24-28 (15 year qualification life).

Policy makers need not – and indeed should not - intervene to make adjustments based on administrative determinations.

D. PV Solar Cost Trends

Additionally, the DOER will have to make certain judgments about the rate of future cost reductions for solar development. This becomes particularly important if the DOER moves to a multi-year SACP schedule [see discussion at p.12, *supra.*]. A declining SACP provides an important disciplining mechanism on the industry, encouraging continual innovation and cost reduction while ensuring that consumers do not overpay for the program.[11]

V. THE SACP MUST BE SET AT A LEVEL THAT WILL ENCOURAGE LOAD SERVING ENTITIES TO CONTRACT FOR SRECS, WHILE CAPPING OVERALL PROGRAM COSTS.

Apart from its role in stimulating consumer demand for solar, the Solar Alternative Compliance Payment serves a two-fold regulatory purpose. First, it must be designed to spur all load serving entities subject to the portfolio requirement to enter into contracts for Solar Renewable Energy Credits with project developers rather than simply absorb the SACP as a cost of doing business. In order to achieve this, the SACP must be set at a price point significantly above the expected market clearing price for SRECs, i.e., it must be sufficiently punitive that LSE's avail themselves of less expensive SRECs generated from Massachusetts customer-sited solar projects. Additionally, the SACP level should provide sufficient headroom to account for any transaction costs associated with negotiating and aggregating SRECs from multiple developers.

The second objective of the SACP is to set an effective ceiling on ratepayer contributions to the solar program goals. Under a well-designed solar share program, few if any SACP payments should be made, since the underlying purpose of the program is sustained and orderly development rather than the accumulation of penalty payments. However, under scarcity conditions, the SACP is intended to set an upper limit on the cost of the program.

These objectives are in tension – the stimulus objective of the SACP argues for a higher value, while rate impact concerns would tend towards a lower SACP value. Ultimately, it will be up to the DOER to reconcile these competing objectives. In general terms, we believe the SACP should float at approximately 20-25% above the forecasted SREC price. New Jersey, for example, has set its initial SACP at approximately $100/MWh above the expected SREC trading price.

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[11] See National Renewable Energy Laboratory, *Letting the Sun Shine on Solar Costs (documenting a 7.3% annual decline in system costs in California); New Jersey Solar Transition Cost Study (4.6% annual decline through 2006).* The New Jersey Board of Public Utilities has adopted a 3% annual rate of decline in SACP levels.
Although not specific to solar set aside programs, PV cost declines are also a fundamental component of leading solar incentive programs such as the California Solar Initiative. Under the CSI program, as rebate blocks are filled, rebate levels automatically ratchet downward according to a pre-defined incentive schedule.
http://www.gosolarcalifornia.org/csi/index.html

VI. GETTING THE ACP RIGHT IS A NECESSARY BUT NOT SUFFICIENT STEP IN CREATING A ROBUST SOLAR MARKET. THE DEPARTMENT MUST ESTABLISH ANCILLARY POLICIES TO ENCOURAGE LONG-TERM CONTRACTING FOR SOLAR RECS.

While the DOER's request for comment rightfully focuses on the ACP given its central role in the orderly and sustained development of the distributed renewable industry under a market-based system, there are other policies that will have an important bearing on the ultimate success of Massachusetts' customer-sited renewable carve-out. Specifically, as the emphasis shifts from up-front incentives to market-based REC payments accruing over the life of the system, there is a need to establish mechanisms to provide some greater predictability and stability of future REC revenues. "Securitization" is of fundamental importance to the solar market for a number of reasons:

- Financing of solar projects depends on investor confidence in a long-term revenue stream to defray the initial capital investment. In nascent SREC markets, investors are likely to greatly discount future revenue streams due to a variety of market and regulatory risks. As noted by a recent Summit Blue report on market-based solar incentive programs, "The project developer must be able to recover enough revenue from the project quickly enough to make it profitable, or at least economically viable. This is problematic for PV projects, where the system is both expensive and the payback period is typically 20 years or more. Furthermore, since the market for SRECs is new and thinly traded, the potential revenues available from SRECs in the out-years are seen as uncertain."[12]

- Load serving entities that assume the RPS obligation may be reticent to enter into long-term contracts with project developers. This may be predicated on expectations of future SREC prices trending downward, or concerns about a shifting regulatory landscape. Additionally, since the RPS obligation is directly associated with serving retail load, any uncertainty surrounding future customer load will deter long-term SREC commitments. The tendency towards short-term SREC purchasing as a risk mitigation strategy will severely constrain the ability of solar developers to obtain project finance.

- Absent long-term contracts, project investors will heavily discount future revenue streams. This risk premium will tend to inflate SREC prices in the immediate term, with the additional costs borne by Massachusetts electric consumers.

There are several potential tools available to policy makers to support greater stability and surety of future SREC revenues. By adopting these measures in conjunction with a REC-based program, the Department will mitigate or eliminate the risk premium and result in lower overall cost of compliance.

[12]New Jersey Solar Transition Cost Study at 19.

- Multi-year SACP schedule. The Board should consider adopting an ACP schedule for an extended period of time. This provides market participants greater long-term visibility on the upper bound of SREC prices. Additionally, a multi-year schedule sends a subtle but important message to the market that the state is committed to the program for the long-haul.

  Our recommendation would be for the Board to establish an SACP schedule of 8-10 years duration. Before the conclusion of each energy year, the Board would establish an SACP value for the new terminal year based on then-existing information. However, the Board should not recalibrate SACP levels after they have been set except under extraordinary circumstances; to do so would upset investment backed expectations and rattle the confidence of market participants.

- Encourage long-term contracting for SREC's. Given the importance of securing long-term SREC contracts to solar developers' ability to obtain project financing, states have wrestled with different approaches for providing this revenue surety within a competitive framework. Some states, such as Maryland, have opted to require retail suppliers to enter into SREC contracts of a minimum 15 years in duration with price determined through negotiation.[13] Other states, such as New Jersey, have enlisted the distribution utility to play an intermediary role in conducting auctions for long-term SREC contracts and selling bundled SRECs to energy suppliers.[14] We encourage Massachusetts policymakers to consider appropriate securitization methods under the state's statutory and programmatic framework.

VII. RATE IMPACT CAPS CAN OFFER ASSURANCES THAT SOLAR DEVELOPMENT WILL BE AFFORDABLE.

SunEdison supports in principle the establishment of rate impact caps within a long-term solar development program. This will assure that the development of renewable resources that provide long-term price stability not unduly expose ratepayers to short-term rate increases. Rate impact caps will also reinforce the need for the most efficient market stimulus mechanisms.

What constitutes an "acceptable" short-term program cost must be determined by the responsible agencies; however, we recommend a rate impact limitation of 1-2%. If the actual dollar-for-dollar costs incurred solely for the purchase of solar renewable energy credits and rebates in any one year is greater than or equal to 1-2% of annual electric retail costs, the Department may delay the scheduled increase in portfolio requirements until such time as these costs are again below 1-2% of annual electric retail costs.

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[13] Md. Public Utility Companies Code §7-701 et. seq.

[14] See New Jersey Board of Public Utilities Docket No. EO0107744, In the Matter of Renewable Energy Portfolio Standards: Amendments to the Minimum Filing Requirementsfor Energy Efficiency, Renewable Energy, and Conservation Programs; and for Electric Distribution Company Submittals in Connection with Solar Financing, Order dated August 7, 2008. The SREC Financing Model adopted by the Board is transitional, covering a three-year period and applicable to approximately 50% of the overall SREC market.

VIII. CONCLUSION

SunEdison appreciates the opportunity to provide input to the Department prior to its formulation of an implementation strategy for the customer sited renewable set-aside mandate set forth in the Green Communities Act. In sum, we believe the GCA offers an unprecedented opportunity for Massachusetts to establish a world class solar PV marketplace. To take full advantage of this opportunity, the Department must:

1. Establish a solar share requirement within the new customer-sited renewable technology set aside;
2. Set reasonable long-term annual solar growth targets that ultimately lead to a self-sustaining market in Massachusetts – we recommend the DOER evaluate the costs and benefits of a solar PV deployment target of 2% of retail load by 2017;
3. Transition from the current solar program rebate scheme to a market-based SREC trading program;
4. Establish SACP values based on a careful analysis of solar project economics and incentives necessary to encourage suppliers to procure SRECs rather than absorb compliance penalties – the appropriate SACP level is a function of other important policy choices regarding qualification life and SREC revenue securitization;
5. Adopt policies to encourage long-term contracting in SRECs by RPS-responsible entities as part and parcel of a market-based program;
6. Continue to offer rebates as a supplement to SREC revenues within the residential and small commercial market segments, and other hard-to-reach markets; and
7. Consider imposing a rate impact circuit breaker to ensure that solar deployment will not cause undue short-term rate pressures.

Respectfully submitted,

Fred Zalcman
Director of Regulatory Affairs – Northeast States

Renewables Portfolio Standards: An Opportunity for Expanding State Solar Markets

Ryan H. Wiser

Lawrence Berkeley National Laboratory

State PV Peer Network Conference Call

State Solar Policy Initiatives:

Recent Developments and Lessons Learned

July 11, 2008

Presentation Overview

1. Overview of State RPS Policies
2. Supporting Solar within State RPS Policies
3. Experience So Far, and Projected Impacts
4. Major Design Issues of Note
5. Conclusions

Focus is on solar photovoltaics and solar thermal electric, and not solar hot water, solar heating/cooling, day-lighting, etc.

What Is a Renewables Portfolio Standard?

Renewables Portfolio Standard (RPS):

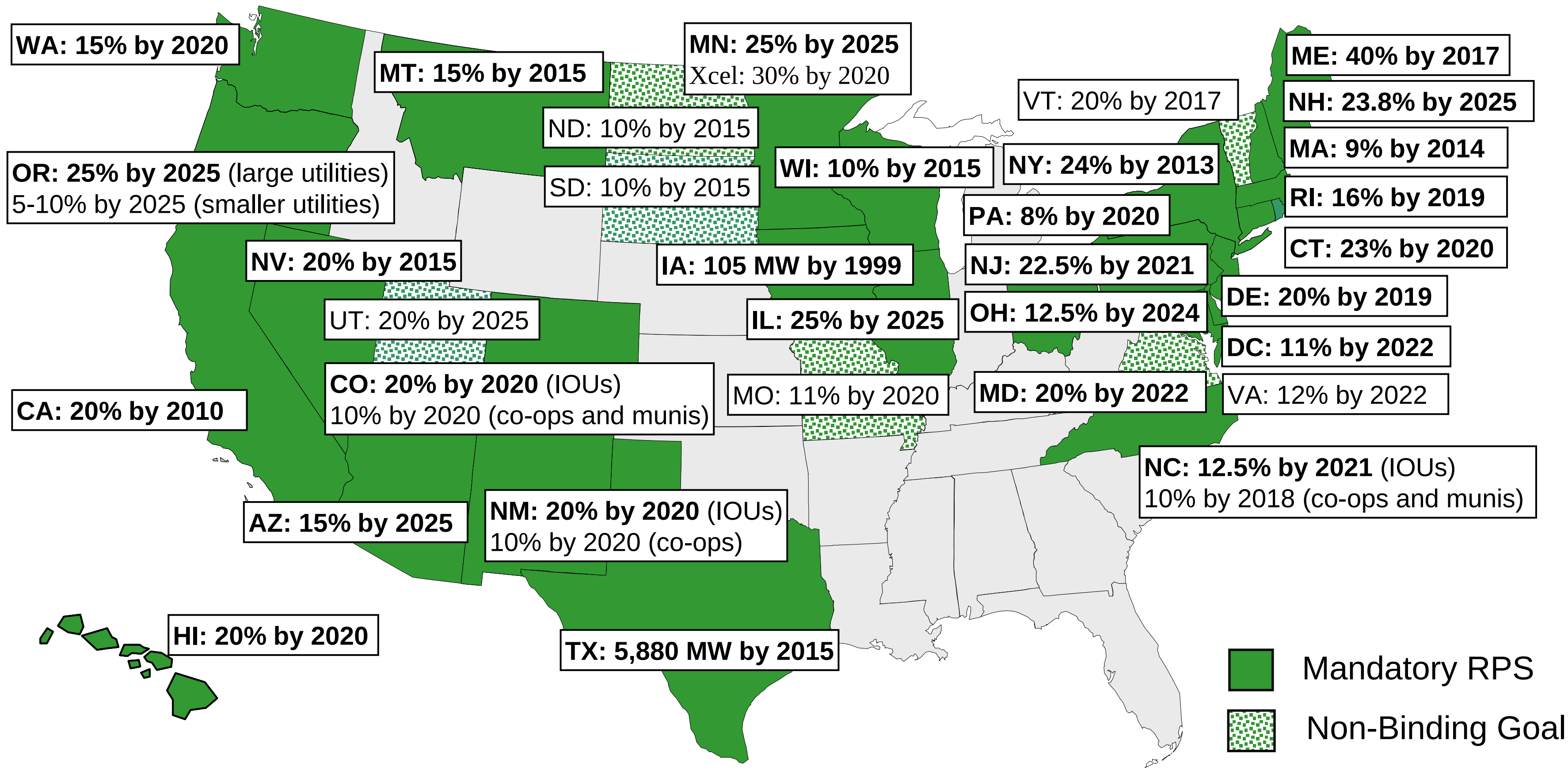
- A requirement on retail electric suppliers…
- to supply a minimum percentage or amount of their retail load…
- with eligible sources of renewable energy.

Typically backed with penalties of some form

Often accompanied by a tradable renewable energy certificate (REC) program, to facilitate compliance

Never designed the same in any two states

State RPS Policies Exist in 26 States and D.C.; 6 States Have Non-Binding Goals

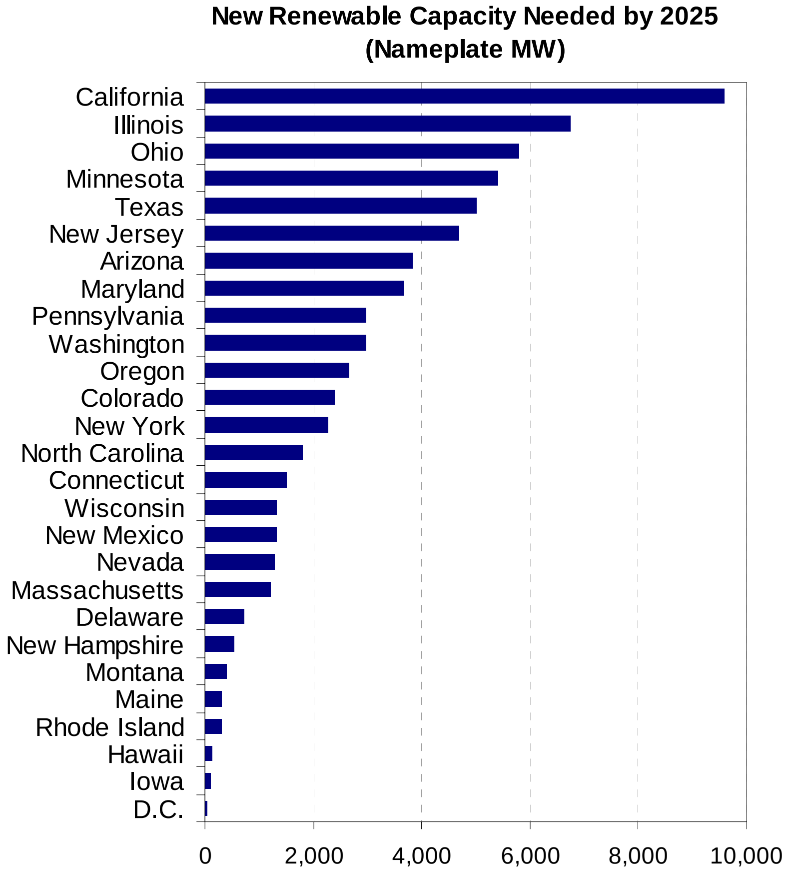


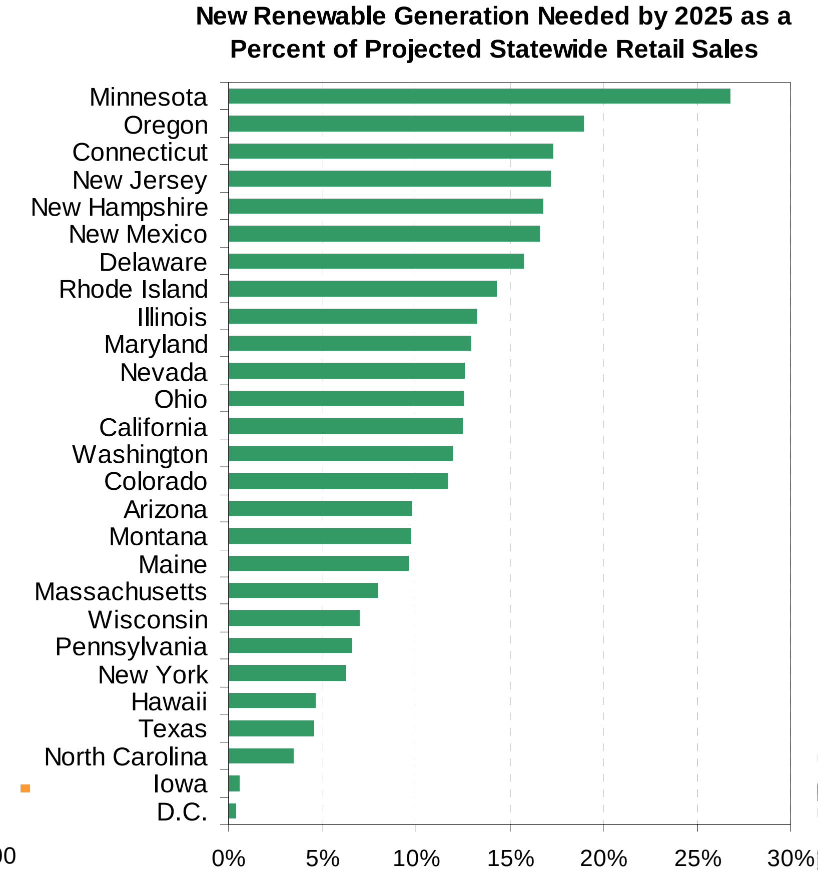
Source: Berkeley Lab

Most policies established through state legislation, but some through regulatory action (NY, AZ) or voter-approved initiatives (CO, WA)

Future Impacts of Existing State RPS Policies Are Projected To Be Relatively Sizable

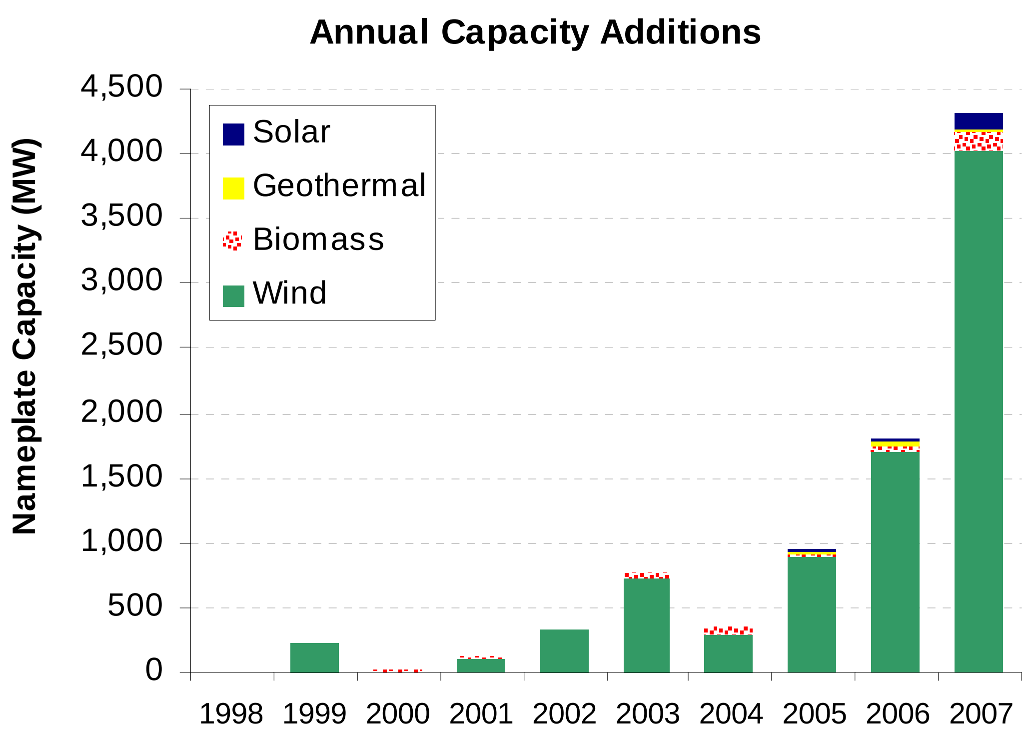
- Roughly 69 GW of new renewables capacity by 2025, if full compliance is achieved (increases to 86 GW if non-binding renewable targets are included)
- The 69 GW would represent ~5.4% of total projected generation in 2025
- 17% of projected load growth from 1999-2025 met by this new generation

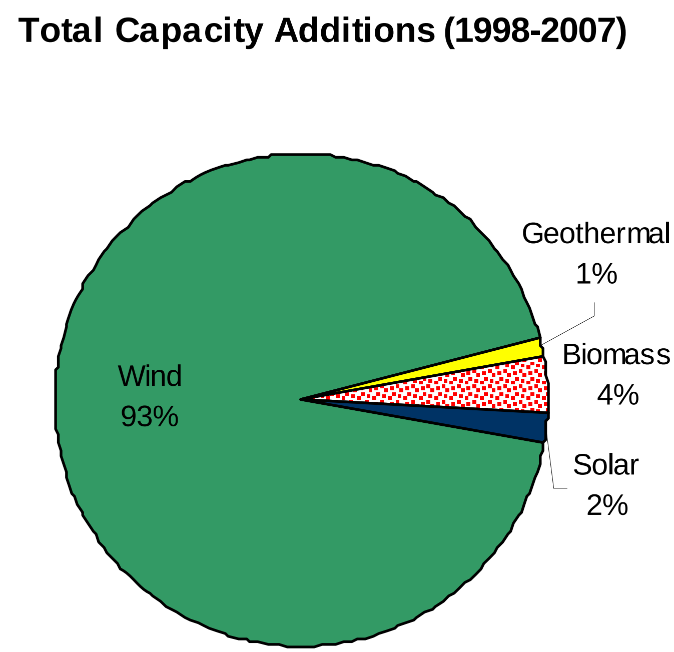




But… Solar Has Not Been a Major Contributor to RPS Compliance So Far

Non-Hydro Renewable Energy Capacity Additions in RPS States





The Problem for Solar Electricity Under Traditional RPS Policies

- Traditional RPS, whereby all eligible resources compete, can be effective in supporting least-cost projects
- But is not likely to provide adequate support for emerging technologies, and smaller projects:
  - Cost and solicitation barriers
- 12 of 27 RPS policies provide no differential support for solar/distributed energy; experience shows that:
  - ➲ These policies are unlikely to provide meaningful support to customer-sited PV in the near term
  - ➲ With the exception of the Southwest, these policies are unlikely to greatly benefit solar thermal electricity

More Generally, For Solar to Succeed in an RPS, the Following Must Be Considered

- **Eligibility**
  - Are all forms of solar electricity eligible?
  - Are customer-sited generators eligible?
- **Measurement**
  - Are metering systems or estimation protocols in place?
  - Do mechanisms exist to trade small quantities of RECs?
- **REC Ownership**
  - Do owners of solar systems “own” their RECs?
- **Differential Support for Solar**
  - Does the RPS contain a solar share or credit-multiplier?
  - How are these mechanisms implemented?

States that Provide Differential Support for Solar within an RPS Do So in Two Ways

Set-Aside/Solar Share

– A requirement that some portion of the RPS come from solar specifically, or DG more broadly

Solar Multiplier

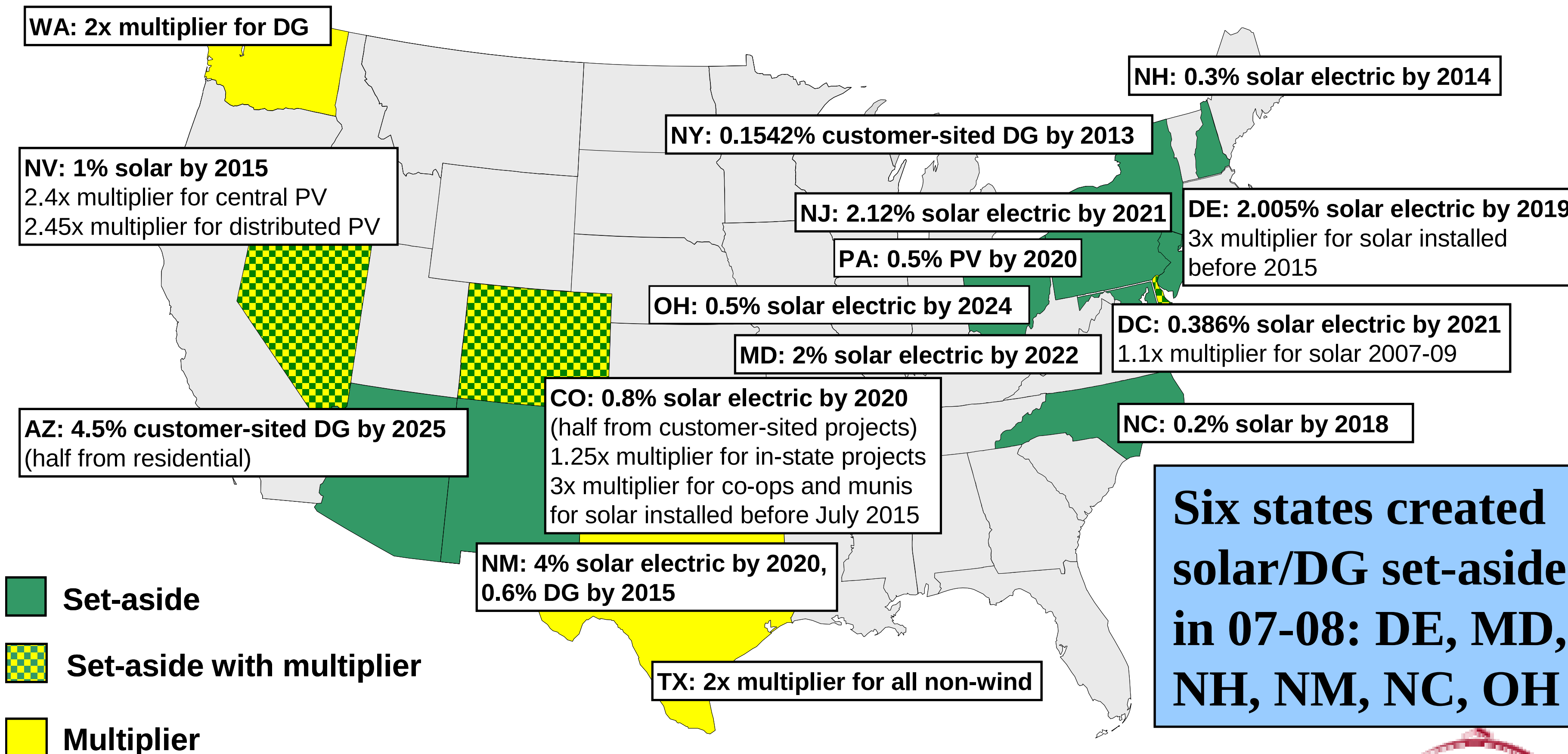
– Provides solar electricity more credit than other forms of generation towards meeting the RPS

Recent move towards set-asides (away from multipliers) due to greater success with these instruments

State governments may also use direct financial incentives to encourage solar power either separate from an RPS (e.g., CA) or to support an RPS (e.g., NJ, NY)

Solar-Specific RPS Designs Are Becoming Increasingly Common

12 states + D.C. have solar or DG set-asides, sometimes combined with credit multipliers; 2 other states only have credit multipliers



Six states created solar/DG set-asides in 07-08: DE, MD, NH, NM, NC, OH

State RPS Set-Asides Can Be and Are Designed in Multiple Ways

- Percentage targets and timeframes
- Solar-specific or broader DG eligibility
- Solar technology eligibility
  - Photovoltaics
  - Photovoltaics and solar thermal electric
  - Inclusion of solar heating and cooling
- In-state vs. out-of-state eligibility
- Requirements for customer-sited capacity
- Use of multipliers in addition to set-asides
- Cost caps, alternative compliance payments, etc.
- Oversight on contracting and incentives

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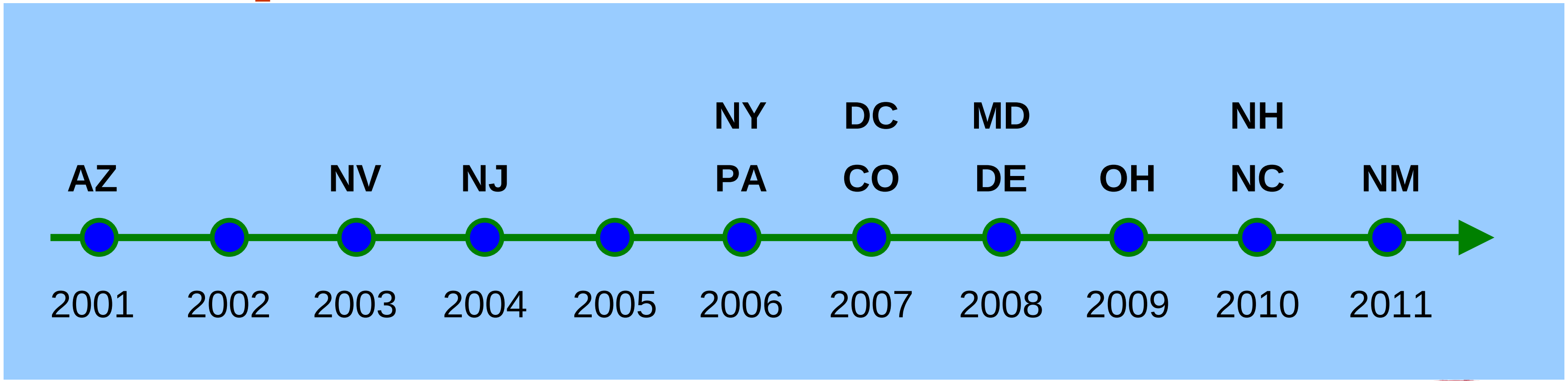
Development of State RPS Set-Asides: Experience Remains Limited

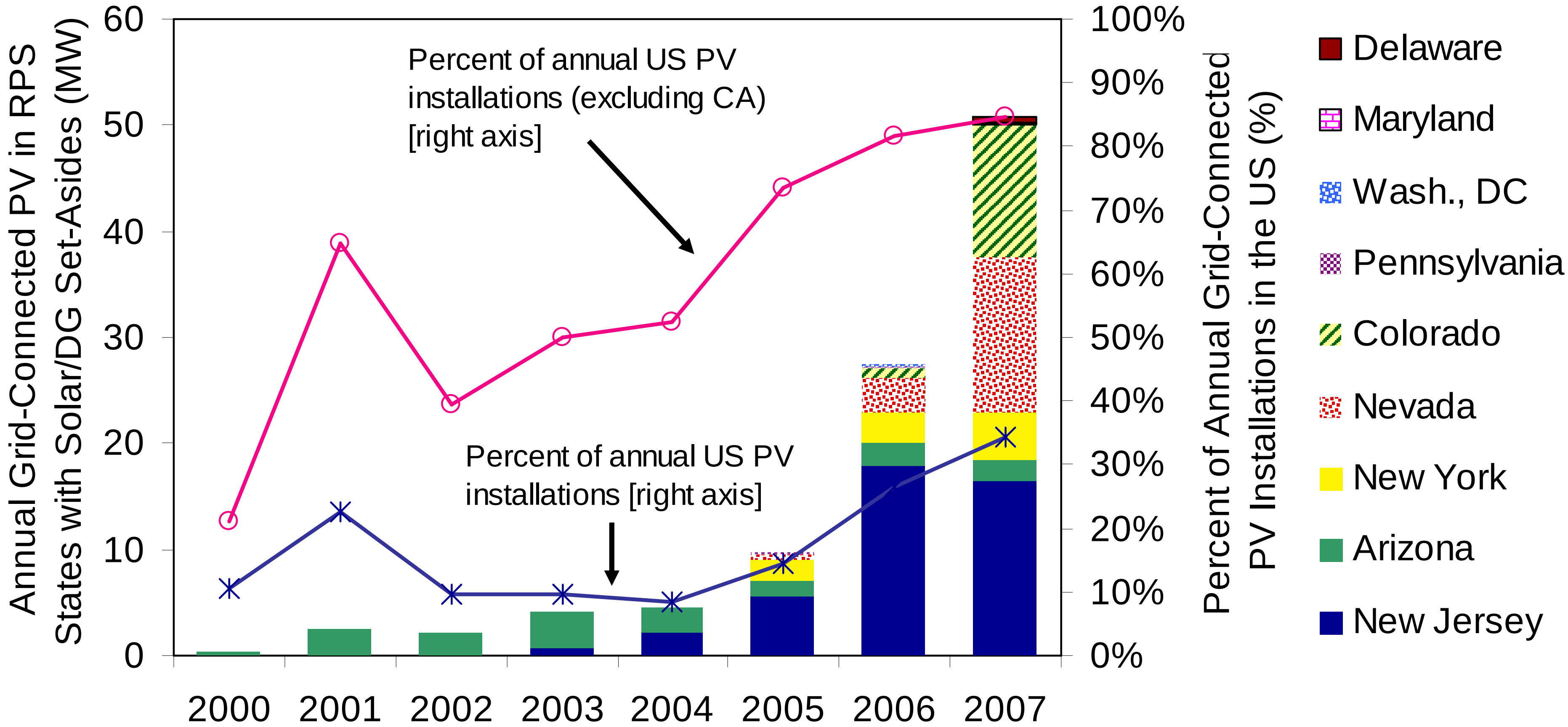
Only three states have had more than three years of experience with a solar/DG set-aside so far:

- Arizona
- Nevada
- New Jersey

First Compliance Year of State RPS Set-Asides



Impact of Solar/DG Set-Asides Is Growing: 102 MW PV from 2000 through 2007



Largest market historically has been NJ, but NV and CO emerged in 2007 as equally sizable; AZ and NY also significant

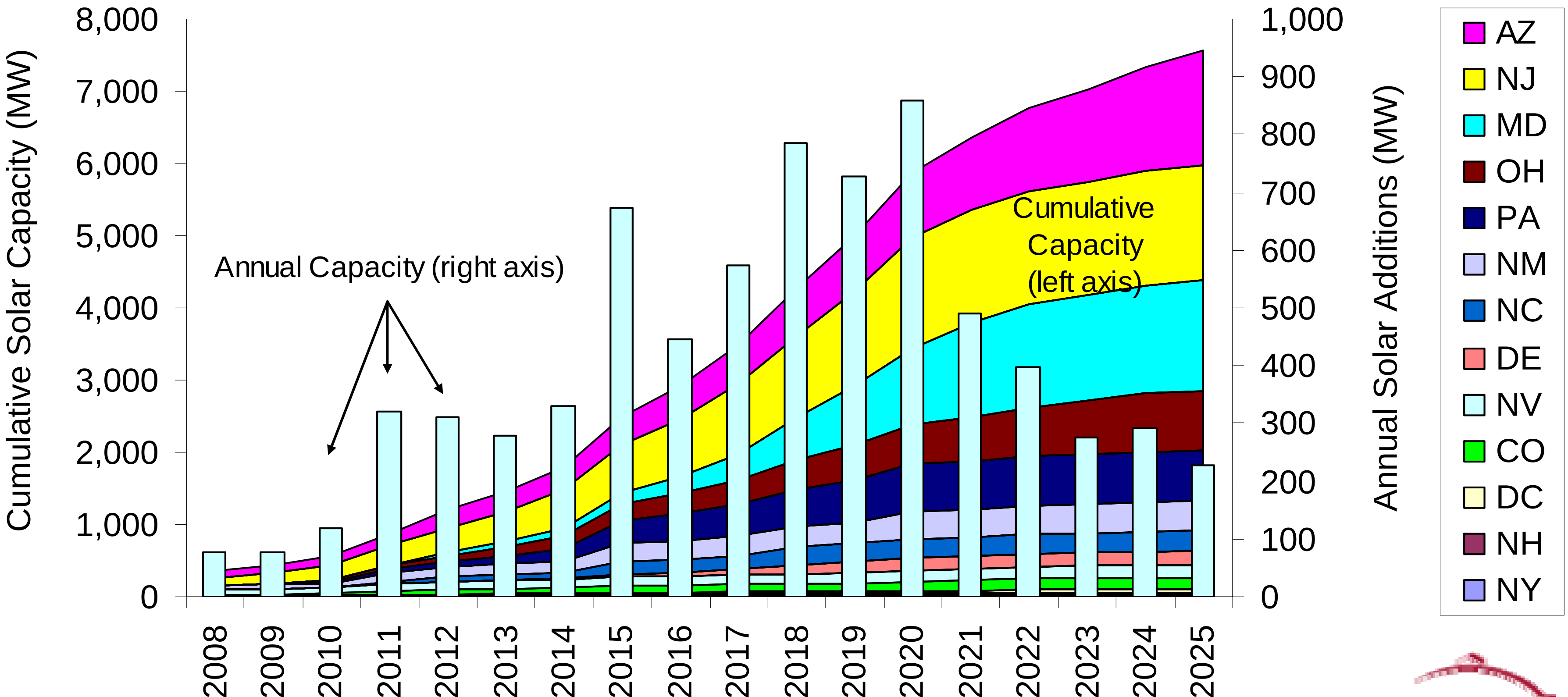
State RPS Set-Asides Provided the Most-Recent Kick-Start for Solar-Thermal Electric

Arizona: 1 MW Saguaro Solar Station came online in 2006; nation's first parabolic trough power plant built since 1990

Nevada: 64 MW Nevada Solar 1 was commissioned in 2007 to help meet the Nevada RPS

Future Impacts Are Projected To Be Substantial, **<u>If</u>** Full Compliance Is Achieved

- 560 MW required by 2010, growing to 7,550 MW by 2025
- Approximately 100 MW/yr through 2010, 300 MW/yr through 2014, and over 600 MW/yr through 2021



Graphic assumes that full compliance is achieved

And the Leading States Are…

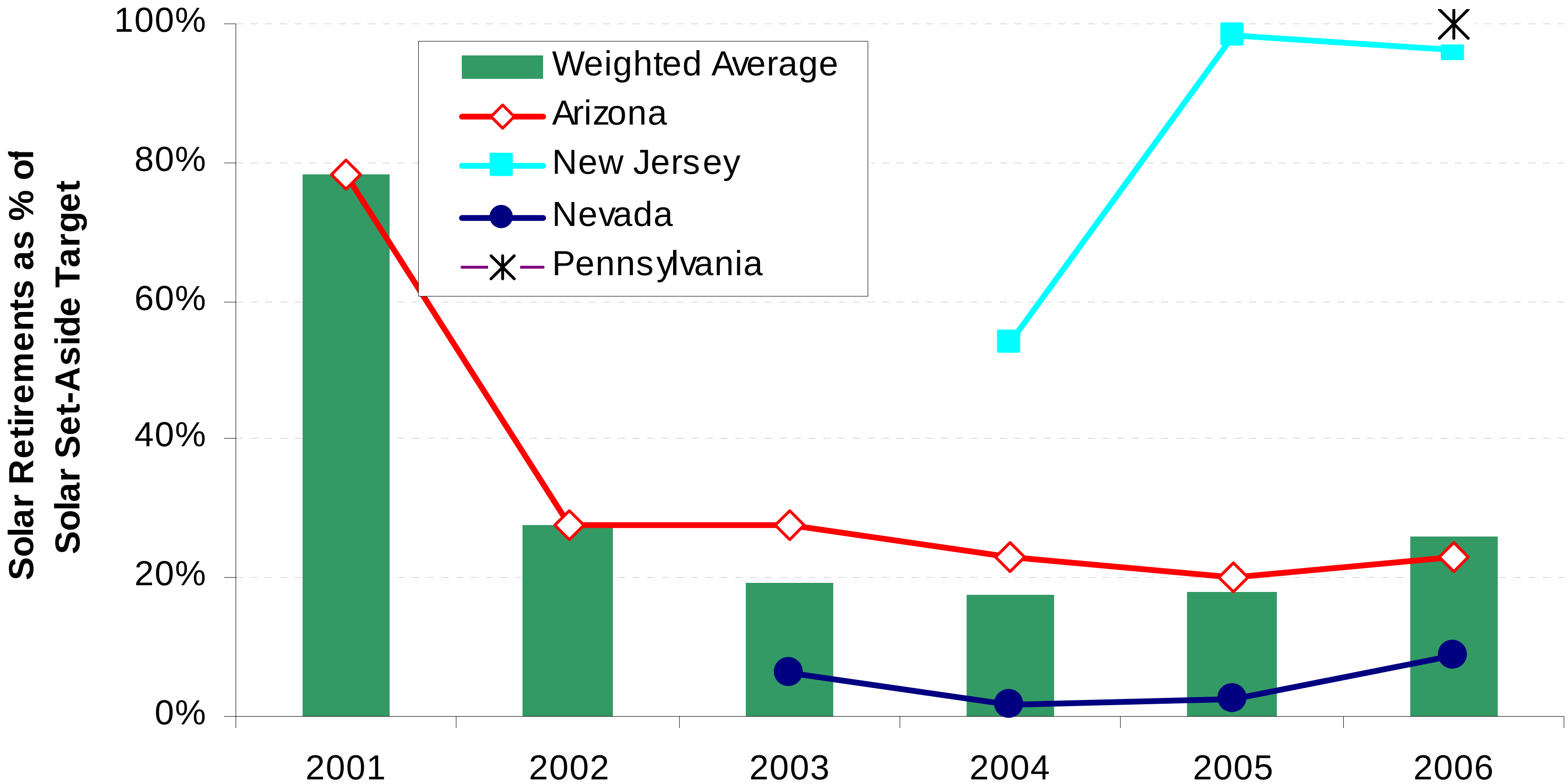
State	2010 Capacity	2025 Capacity	2025 Solar Generation as a % of State Load
Arizona	110 MW	1,600 MW	2.0%
Colorado	29 MW	160 MW	0.4%
Delaware	0.5 MW	190 MW	1.4%
Maryland	14 MW	1,500 MW	2.0%
Nevada	76 MW	180 MW	0.6%
New Hampshire	4 MW	35 MW	0.3%
New Jersey	210 MW	1,600 MW	2.1%
New Mexico	64 MW	420 MW	3.1%
New York	10 MW	15 MW	0.0%
North Carolina	5 MW	280 MW	0.2%
Ohio	14 MW	820 MW	0.5%
Pennsylvania	25 MW	690 MW	0.5%
Washington D.C.	0.5 MW	54 MW	0.4%
Total	**560 MW**	**7,550 MW**	**n/a**

Note: Data are presented in direct-current units, at Standard Test Conditions

- Largest markets driven by these policies in long term include: AZ, NJ, MD, OH, PA
- In near-term, NM, NV, and CO are also significant
- California goal of 3,000 MW equals ~1.5%, lower than NM, NJ, MD, AZ

Beware… States with Set-Asides Are Not Universally Achieving their Solar Targets

Early-year purchase/retirement of solar "RECs", relative to set-aside requirements, has been mixed



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Technical Design Considerations Will Affect the Impact of Set-Asides on Solar Growth

Broader DG set-aside	Competition with other resources makes market size for solar uncertain (AZ, NY)
Credit multipliers	Reduces effective solar % (CO, DC, DE, NV)
Eligibility of solar thermal electric	Affects fate of PV (PA only allow PV; NV provides extra credit to PV)
Eligibility of utility-scale solar	Affects fate of customer-sited installations (AZ, CO, NM, NY all have DG requirements; NV has multiplier)
Qualification for out-of-state solar	Impacts the degree to which solar is installed in-state

Of course, the existence of Federal tax incentives also matters!

Cost Caps, ACP Levels, Funding Limits May Impede Achieving Solar Targets

Alternative Compliance Payments

- NH ($150/MWh), DE ($250-$350/MWh), DC ($300/MWh), MD ($450/MWh dropping to $5/MWh), NJ ($711-$595/MWh)
- Many of these are **below** what is needed to make solar economic, absent other forms of state funding

Cost Caps

- CO (1.7%), MD (1%), NC (1.9%), NJ (2%), NM (1.8%), OH (3%)
- Several of these could become binding

Funding Limits

- AZ, NY
- AZ limit has been *severely* binding in the past

Possible Force Majeure Events

- NV, PA, others

Contracting and Incentive Policies Are Critical to the Success of a Set-Aside

Reliance on short-term REC purchases to meet solar RPS likely to be costly and ineffective, given political risk; of most concern in states with retail electric competition

- **Long-term REC contracting**
  - Implicit Encouragement: NJ (8 year ACP schedule; investigating securitization)
  - Strict Requirements: MD (>15 yrs), NC (as long as needed by generator), CO (>20 yrs), NV (>10 yrs)
- **Up-front payments for smaller PV systems**
  - CO, NV, AZ, NJ, NY, MD

Conclusions

- Traditional RPS designs will do little to support customer-sited PV in the near term
- State RPS policies that include solar or DG set-asides are becoming more popular, and are increasingly driving solar development
- RPS policies that only have credit multipliers for solar have not yet seen significant solar additions
- Greater focus on design details is needed; many solar set-asides appear likely to need re-design

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